BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Joint Application of Wisconsin Electric Power Company and Wisconsin Gas LLC for Authority to Adjust Electric, Natural Gas and Steam Rates—Test Year 2020

Docket No. 5-UR-109

DIRECT TESTIMONY OF RONDA L. FERGUSON

Q. Please state your name, address, and title.

A. My name is Ronda L. Ferguson. My office address is P.O. Box 19001, Green Bay, Wisconsin 54307-9001. I am employed by WEC Business Services, serving all of the WEC Energy Group utilities, including Wisconsin Electric Power Company ("WEPCO") and Wisconsin Public Service Corporation ("WPSC") as the Manager of Regulatory Compliance and Advocacy.

Q. Please briefly describe your education, professional and utility background.

A. I graduated from South Dakota School of Mines and Technology in 1992 with a Bachelor of Science Degree in Mechanical Engineering. In 1992, I was employed by WPSC in the Licensing and Systems Department for the Kewaunee Nuclear Power Plant. I was in that position for three years. After being in the Gas Engineering area for one year, I took the position of Rate Planner in 1996, Supervisor of Electric Retail Pricing in 2005, and my current position of Manager of Regulatory Policy in 2012. In that position, I am involved in rate-related engineering studies, rate development and rate administration. Since the acquisition of Integrys Energy Group, Inc. by WEC Energy Group my title has been Manager of Regulatory Compliance and Advocacy.

Q. Have you testified before the Commission previously?

A. Yes, I have testified before the Commission in a number of WPSC's rate cases.

Q. What is the purpose of your testimony?

A. I describe WEPCO's general approach to electric rate design and present WEPCO's proposed electric rate design for 2020 and 2021.

Specifically, I will address the following items related to electric rates and rules:

1. Proposed revenue allocation to rate classes;

2. Rate Design for Residential Customers, with a proposed 4.90% annual rate increase for Rg-1 customers in 2020 and 2021;

3. Rate Design for Small Energy Only Commercial Customers, with proposed annual rate decreases of 0.24% (2020) and 0.44% (2021) for Cg-1 customers, and of 2.00% in both years for Cg-6 customers;

4. Rate Design for Medium and Large Demand Commercial Customers, with proposed annual rate decreases of 1.66% (2020) and 1.01% (2021) for Cg-2 customers, and proposed annual rate increases of 2.00% for Cg-3 customers in both years;

5. Rate Design for the Primary Classes, with proposed annual rate increases of 3.13% (2020) and 1.97% (2021) for CP customers;

6. Customer-Owned Generation, including a proposed new fixed cost recovery charge for CGS-NM and CGS-NP customers;

7. Lighting;

8. Energy for Tomorrow; and

9. Miscellaneous Tariff Changes.

<u>Rate Design Principles Utilized</u>

Q. Please give an overview of the rate design philosophy reflected in WEPCO's proposed electric rate design.

A. Our basic philosophy is to implement James Bonbright's eight criteria of a desirable rate structure. Mr. Bonbright is the author of the oft-cited "Principles of Public Utility Rates." These criteria are:

1. Simplicity, understandability, public acceptability, and feasibility of application.

2. Freedom from controversies as to proper interpretation.

3. Effectiveness in yielding total revenue requirements.

4. Revenue stability from year to year.

5. Stability of the rates with a minimum of unexpected changes adverse to existing customers.

6. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.

7. Avoidance of “undue discrimination” in rate relationships.

8. Efficiency of the rate design in discouraging wasteful use of service while promoting all justified types and amounts of use (consideration of energy conservation and load management).

Consistent with these criteria, WEPCO follows five general principles when developing rates:

1. A fully-allocated, embedded cost-of-service study should be used as a guide for determining revenue requirements for the individual rate schedules.

2. Both embedded and marginal costs should be used as guides in rate design.

3. Where increases or decreases would be substantial, based upon cost of service data, the change in rates should be moderated to incorporate reasonable rate stability.

4. Rate design should reflect cost of service to the extent practical.

5. Rate design should take into consideration the competitive impact on the continued viability of existing businesses, the ability to attract new businesses to the area, industry restructuring and evolution.

Q. How do these principles relate to WEPCO’s rate proposal in this case?

A. Consistent with these principles, WEPCO is seeking targeted two-year stepped overall electric rate increases of 2.9% effective in Test Year (“TY”) 2020 and 2.9% in 2021. The WEPCO Cost of Service Study (“COSS”) shows a wide variance in the cost to serve customer classes relative to current rates, from a 6.34% deficiency for residential customers to a 14.53% surplus collection in the lighting rate schedules. To temper increases to individual rate classes and promote stability, rate schedules that showed surplus collections were kept to no increases or slight decreases, whereas rate schedules that showed deficiencies were adjusted toward cost of service. WEPCO recognizes that if the electric revenue requirement changes significantly, these limits and the overall rate proposals may need to be revised.

Description of Schedules

Q. Please describe the contents of Schedule 1 of Ex.-WEPCO WG-Ferguson-1.

A. Schedule 1 summarizes current and proposed revenue by rate schedule, including the proposed dollar and percentage changes for 2020 and 2021. Variances from the income statement are noted on a reconciliation line item on the exhibit.

Q. Please describe the contents of Schedule 2 of Ex.-WEPCO WG-Ferguson-1.

A. Schedule 2 shows a summary of current and proposed revenue by rate schedule, including the proposed dollar and percentage changes and proposed COSS results for 2020 and 2021. The proposed rates recover WEPCO's forecasted revenue requirement for 2020 and 2021, as presented by other witnesses. Present revenues vary due to the adjustments noted on Schedule 1 of this Exhibit. WEPCO's proposed revenues are close but not exactly equal to the filed revenue requirement forecast because the revenue requirement is subject to change through the rate case process and perfect precision is not required at this time.

Q. Please describe the contents of Schedule 3 of Ex.-WEPCO WG-Ferguson-1.

A. Schedule 3 shows the test year billing data by rate schedule, the current and proposed revenue, as well as the dollar and percentage rate changes for 2020 and 2021. The percentage rate change for each rate schedule is the percentage change for that billing unit. The proposed rates in this schedule reflect a fair and equitable distribution of WEPCO's jurisdictional revenue requirement, taking into account all pertinent factors.

Q. Please describe Schedule 4 of Ex.-WEPCO WG-Ferguson-1.

A. Schedule 4 shows typical monthly bills for various levels of consumption for the residential rate schedule for 2020 and 2021. The first column (A) shows the monthly consumption level; the next two columns (B and C) show the monthly and annual bills under current rates for TY 2020; and the following two columns (D and E) show the monthly and annual bills under proposed rates for TY 2020. The next two columns (F

and G) show the total dollar and percentage change in bills. The next two columns (H and I) show the same proposed monthly and annual bills for 2021 followed by the percent and monthly changes from 2020 to 2021 (J and K).

Q. Please describe Schedule 5 of Ex.-WEPCO WG-Ferguson-1.

A. Schedule 5 provides the same detail as Schedule 2, but for the small commercial and industrial customer classes.

Q. Please describe Schedule 6 of Ex.-WEPCO WG-Ferguson-1.

A. Schedule 6 provides the same detail as Schedule 2, but for the medium Cg-2 commercial rate schedule.

Q. Please describe Schedule 7 of Ex.-WEPCO WG-Ferguson-1.

A. Schedule 7 shows the percentage increases applicable to the CP customers by frequency with the proposed rate increases.

Q. Please describe Schedule 8 of Ex.-WEPCO WG-Ferguson-1.

A. Schedule 8 illustrates the derivation of Act 141 credits for the Large Energy Customers as defined by 2005 Act 141.

Q. Please describe Schedule 9 of Ex.-WEPCO WG-Ferguson-1.

A. Schedule 9 shows the calculation of the embedded credit allowances.

Q. Please describe Schedule 10 of Ex.-WEPCO WG-Ferguson-1.

A. Schedule 10 calculates the fixed distribution costs not collected in the customer's facilities charges for energy-only rate schedules.

Q. Please describe Schedule 11 of Ex.-WEPCO WG-Ferguson-1.

A. Schedule 11 contains new or redlined tariff changes.

Q. Please describe Schedules 12 through 15 of Ex.-WEPCO WG-Ferguson-1.

A. These schedules all relate to steam rates, and I will describe them in greater detail later in my testimony.

Revenue Allocation

Q. Please provide a general overview of how WEPCO groups the different rate schedules for purposes of rate making.

A. WEPCO's rate schedules are divided into groups based on historical rate design and COSS groupings. For example, the secondary rates have six COSS groupings. One of these groups contains the Rg-1 (residential) and Fg-1 (farm) rate schedules. The facilities and energy rates for these rate schedules are set at the same levels but the rate increases vary due to the load factors of each rate schedule. The medium commercial customer group contains the Cg-3, Cg-3C (curtailable) and Cg-3S (seasonal) rate schedules. The energy and demand rates are set at the same levels for these rate schedules; only the facility and curtailable credits differ. The primary group contains the CP and market-based rates. The Cp-1 and Cp-3 rate schedules (Cp-3, Cp-3C, Cp-3S) have similar energy and demand rate levels. They also offer different curtailable credits. The lighting and miscellaneous group contains lighting, sirens and telecom equipment services.

Q. Please provide a general overview of the COSS results.

A. These results are shown in Ex.-WEPCO WG-Ferguson-1, Schedule 2. Residential customers show revenue deficiencies ranging from -1.97% to 6.34% for TY 2020 and from 2.88% to 3.64% in 2021. Small commercial customers show surplus collections ranging from 8.28% to 3.79% for TY 2020 and revenue deficiencies between 2.76% and 2.80% in 2021. The Cp rate schedules have combined revenue deficiencies of 3.84% in TY 2020 and 2.04% in 2021. The lighting and miscellaneous groupings show a surplus collection of 14.53% in TY 2020 and a deficiency of 3.32% in 2021.

Q. Is the Company proposing to set rates as proposed in the COSS results?

A. The Company is proposing to move towards the COSS results while balancing other rate design considerations, including stability and gradualism. For instance, our proposed rate design is intended to avoid the fluctuations that would result for those

customer classes where COSS suggests a rate decrease in TY 2020 and an increase in 2021. WEPCO's proposed rate design also avoids giving some rate schedules large decreases and others large increases.

Q. If the revenue requirement changes significantly due to the Staff audit, would your proposed revenue allocation change?

A. Yes. If that occurs, WEPCO will likely need to submit a revised rate design proposal based on the Staff audit.

Q. Please describe how the tax credit line item was calculated in rate design.

A. The tax credit was allocated based on COSS groups on Ex.-WEPCO WG-Nelson-7. Rate design used the total kilowatt-hours (kWh) in each group (as defined in COSS) to credit the rate schedules on a $/kWh basis.

Q. Please describe the fuel adjustment line item in rate design.

A. The current fuel credit is shown in present rates but all fuel cost recovery in the test years are built into the base rates and therefore there is no fuel adjustment needed in the proposed rates.

<u>Residential and Farm Rate Schedules</u>

Q. Please describe the residential rate schedule.

A. WEPCO has two residential rate options and one farm rate schedule:

Rg-1: Standard rate with a fixed charge and a flat volumetric energy charge. This is the default rate for all residential customers.

Rg-2: Two-tier time-of-use (TOU) rate with fixed charge, on-peak energy and off-peak energy. This is an optional rate.

Fg-1: This rate schedule mimics the Rg-1 rate schedule with the same rate levels but is available to customers using electricity for farming purposes.

Fixed charges are set at the same level for all residential, farm and small secondary commercial rate schedules.

Q. Please describe the overall increase for these rate schedules and how they relate to COSS.

A. The proposed annual rate increases and COSS comparisons for the residential and farm rates are shown below.

Residential and Farm						
	COSS (Costs)			Proposed Rates (Revenues)		
Tariff	**TY 2020**	**2021**	**Rev. Reqmt. 2021**	**TY 2020**	**2021**	**Rev. Reqmt. 2021**
Rg-1 Fg-1	6.34%	3.64%	$1,287,908,125	4.90% 5.14%	4.90% 4.90%	$1,288,628,220
Rg-2	-1.97%	2.88%	$30,975,715	0.55%	0.37%	$30,979,758

To temper the rate increase to the Rg-1 and Fg-1 rate schedules, the proposed revenues take a step toward the COSS results but are less than what the COSS recommends. The Rg-2 rates have slight increases each year. This eliminates the fluctuation from a decrease in one year to a larger increase in the second year that would occur if the rates were set at the COSS levels in each year. The final proposed revenues for Rg-2 are very close to the COSS-proposed revenue requirement.

Q. What facilities charge is WEPCO proposing for the residential and farm rate schedules?

A. WEPCO is proposing to increase the facilities charge by a percentage equal to the overall proposed increase for the rate schedule, or 4.9% for each year. The daily rate will increase from $0.52602/day to $0.55180/day ($16.83/month) in TY 2020 and $0.57885/day ($17.65/month) in 2021 for single phase customers, and to $0.82770/day in TY 2020 and $0.86828/day in 2021 for three phase customers.

Q. How does this proposed rate increase compare to the customer-related charges shown in the WEPCO COSS?

A. As explained in Mr. Nelson's testimony, plant and expenses are functionalized into Production, Transmission, and Distribution. These functions are classified as

Commodity (Energy), Demand (Capacity) and Customer-related costs.

The cost breakdowns for Rg-1 residential customers are shown on Schedule 31 of Ex.-WEPCO WG-Nelson-7. The exhibit calculates the daily customer-related costs to be $0.64 per day ($19.52 per month) for the Rg-1 and Fg-1 farm rates and $0.71/day ($21.66 per month) for the residential TOU Rg-2 rate. Customer-related costs are independent of the customer's consumption and are therefore fixed. The full cost of service lines, metering, billing, and miscellaneous costs are included in customer costs, as are a minimal portion of the secondary distribution lines, line transformers, and the primary feeder system of poles, conduits and conductors. A breakdown of the customer-related costs for Rg-1 is shown below.

Residential Customer-Related Costs – Single Phase	
Cost Category	**$/day**
Distribution Overhead	$0.23
Distribution Underground	$0.08
Transformer – Customer classified	$0.03
Service Lines	$0.07
Metering	$0.05
Billing	$0.17
Total	**$0.64**

As further shown on Schedule 31, the customer-related costs for three phase customers are a little more than double those of single phase customers. Prior to 2015, the three phase facilities charges were double the single phase facilities charges. In Docket 05-UR-107, for TY 2015, the single phase and three phase facilities charges were set at the same level. The Company proposes to reinstate a differential between the single phase and three phase facilities charges by increasing the three phase facilities charge by a factor of 1.5. This is a step toward the COSS-recommended value and WEPCO may revisit the issue in future rate case proceedings to move this charge closer to that value.

<u>Energy-Only Small Commercial Rate Schedules</u>

Q. Please describe the standard small commercial energy-only rate schedules.

A. WEPCO has the following small commercial energy-only rate schedules:

Cg-1: Standard rate with fixed charge and a flat energy charge. This is the default rate for commercial customers with monthly consumption of less than 329 kWh/day or approximately 10,000 kWh per month. The TSSM and TSSU rate schedules, available for auxiliary power at substation rates, are also tied to the Cg-1 rate levels.

Cg-6: Two-tier TOU rate with facilities charge, on-peak energy and off-peak energy. This optional rate is available to commercial customers with monthly consumption less than 329 kWh/day or 10,000 kWh/month.

Q. What rate levels is WEPCO proposing for Cg-1 and Cg-6?

A. WEPCO's COSS indicates that these rate schedules should see a decrease in TY 2020 and an increase in 2021. As explained above, to avoid annual fluctuation and help temper increases to other rate schedules, the proposed rate design takes a step toward COSS but still shows an overall surplus collection.

Q. Please describe the overall decrease for these rate schedules and how they relate to COSS.

A. The proposed annual rate reductions and COSS comparisons for the commercial energy-only rates are shown below.

Commercial Energy Only Cg-1 and Cg-6						
	COSS (Costs)			Proposed Rates (Revenues)		
Tariff	**TY2020**	**2021**	**Rev. Reqmt. 2021**	**TY2020**	**2021**	**Rev. Reqmt. 2021**
Cg-1	-3.79%	2.97%	$236,758,007	-0.24 %	-0.44 %	$237,071,604
Cg-6	-8.28%	2.77%	$15,895,245	-2.00 %	-2.00 %	$16,154,964

*Cg-1 includes Energy for Tomorrow for small commercial customers and TSSM & TSSU.

Q. What facilities charges is WEPCO proposing for these rate schedules?

A. The facilities charges for Cg-1 and Cg-6 are currently set at the same level as the residential and farm rate levels. The Company is proposing to maintain these relationships, meaning the Cg-1 and Cg-6 facilities charges would increase by 4.9%.

Q. What is WEPCO proposing for the energy charges for the Cg-6 rate schedule?

A. The Company is proposing to maintain the current differential between the on-peak and off-peak energy charges that was set in the last case. The energy rates decrease by approximately 5% in 2021.

<u>Medium Secondary Demand – Cg-2</u>

Q. What changes does WEPCO propose to the fixed and customer demand charges intended to recover the costs of providing distribution service?

A. WEPCO is proposing to increase the monthly fixed charge from $34.34 ($1.12590/day) to $36.60 ($1.200/day) in TY 2020 and $41.48 ($1.3600/day) in 2021. This sets the fixed charge closer to the COSS-supported amount, as shown on Schedule 30 of Ex.-WEPCO WG-Nelson-7. In Docket 05-UR-107, the Company added a $0/kW customer demand charge to the tariff so that customers could get used to seeing their demands on their bills. As previewed in Mr. Rogers' direct testimony in that docket, the Company is now proposing to phase in the customer demand charge. Specifically, the Company is proposing to implement a customer demand charge of $2.00/kW in 2021. The Company proposes to postpone this charge until then to prevent having to bill it in 2020 as the current billing system is being retired. These rate levels are forecasted to produce $16,359,401 of revenue, approximately 47% of the COSS allocation of $34,730,891 of distribution-related costs shown on Schedule 30 of Ex.-WEPCO WG-Nelson-7.

Q. What generation charges does WEPCO propose for this customer class?

A. WEPCO proposes that generation and transmission costs for Cg-2 customers be collected through a combination of on-peak demand charges and on-peak and off-

peak energy charges. Due to under-collection of the distribution costs in the facilities and customer demand charges, WEPCO must collect the remaining distribution costs in the on-peak demand and energy charges. WEPCO is proposing to maintain the current energy and demand rates for TY 2020 and to decrease the on-peak and off-peak energy charges for 2021. As shown on Schedule 30 of Ex.-WEPCO WG-Nelson-7, WEPCO should be collecting $152,745,626 through a combination of the on-peak demand and on-peak and off-peak energy charges. With the increase in distribution charges and a 10.89% decrease in energy charges, WEPCO is taking a step toward COSS, and will continue to work towards COSS in future rate cases.

Q. What is the overall impact of these changes on the Cg-2 customer class?

A. The proposed rate design reflects a 1.66% decrease for TY 2020 and a 1.01% decrease for 2021, compared to the COSS allocation of -5.55% for TY 2020 and +2.57% for 2021. The proposed revenue collection for 2021 is $187,251,703, which is close to the final COSS revenue requirement of $186,629,373 for that year.

Q. With this rate design, including the added customer demand charge, what is the projected impact on the individual customers in the Cg-2 customer class?

A. The individual impacts for 2021 are shown on Schedule 6 of Ex.-WEPCO WG-Ferguson-1 based on historical 2018 billing data. Out of the 7,623 customers for whom we have 12 months of data in 2018, 98% of them will see a small bill increase (4% or less). Of the remaining 126 customers who will see an increase of more than 4%, the vast majority (119) have zero consumption on their meter.

<u>Large Secondary Demand – Cg-3 Rate Schedules</u>

Q. Please describe the large secondary rate schedules.

A. Large secondary customers take service under three Cg-3 rate schedules: Cg-3, Cg-3C (curtailable) and Cg-3S (seasonal):

Cg-3: Available to customers that use at least 986 kWh per day or approximately 30,000 kWh per month. The rate schedule consists of a

facilities charge, customer demand, on-peak demand and on-peak and off-peak energy rates.

Cg-3C: This curtailable rate is closed to new customers. The facilities charges are higher than the standard Cg-3 but the energy and demand charges mimic the Cg-3 rate. This rate has a curtailable credit of $0.02080/kWh. The customer is responsible for reducing load during a curtailable event.

Cg-3S: This seasonal curtailable rate also is closed to new customers. The facilities charge is the same as the Cg-3C rate and the demand and energy rates are equal to the standard Cg-3 rate. It offers a $2.00/kW curtailable credit from April to September, when the customer is responsible for reducing load during an event.

Q. What changes does WEPCO propose to the Cg-3 fixed and customer demand charges intended to recover the costs of providing distribution service?

A. WEPCO's proposed facility and customer demand charges are shown in the following tables:

Large Secondary (Cg-3) Facilities Charges					
Tariff	**COSS (Costs)**		**Proposed Rates (Revenues)**		
	Charge	**Rev. Reqmt. 2021**	**TY 2020**	**2021**	**Rev. Reqmt. 2021**
Cg-3	$4.35/day*	$9,916,943*	$1.50/day	$2.00/day	$4,516,094
Cg-3C Cg-3S	*	*	$3.65/day	$3.75/day	$43,921
Extra Meter	$0.30/day	Included above	$0.20/day	$0.25/day	$313,808
Total					$4,873,822

*The Cg-3, Cg-3C and Cg-3S rate schedules are combined in the COSS.

Large Secondary (Cg-3) Customer Demand Charges					
Tariff	**COSS (Costs)**		**Proposed Rates (Revenues)**		
	Charge	**Rev. Reqmt. 2021**	**TY 2020**	**2021**	**Rev. Reqmt. 2021**
Cg-3	$4.17KW*	$61,689,681*	$2.50/KW	$2.55/kW	$46,842,775
Cg-3C Cg-3S	*	*	$2.50/KW	$2.55/kW	$394,738
Total					$47,237,513

*The Cg-3, Cg-3C and Cg-3S rate schedules are combined in the COSS.

These rate levels are forecasted to produce $52,111,336 of revenue in 2021, approximately 73% of the COSS allocation of $71,606,624 of distribution-related costs shown on Schedule 30 of Ex.-WEPCO WG-Nelson-7.

Q. What generation charges does WEPCO propose for this customer class?

A. Similar to the Cg-2 rate schedule, WEPCO proposes that the generation and transmission costs for Cg-3 customers be collected through a combination of on-peak demand charges and on-peak and off-peak energy charges. For TY 2020, WEPCO is proposing a slight increase in the demand charges and a slight decrease in the energy charges. For 2021, WEPCO is proposing to maintain the TY 2020 on-peak demand charge and to further decrease the on-peak and off-peak energy charges.

Q. What is the overall impact of these changes on the Cg-3 customer class?

A. The proposed rate design reflects an approximate 2% increase for each of the Cg-3 tariffs for each of the test years, compared to the COSS-based increase of 2.10% for TY 2020 and 2.30% for 2021. The proposed revenue collection for 2021 is $621,493,464, nearly identical to the 2021 COSS revenue requirement of $621,478,205 for the combined Cg-3 rate schedules.

CP Rate Schedules

Q. Please describe the CP rate class.

A. The CP rate class includes commercial and industrial customers served at primary voltages of 3,180 volts or higher. CP customers' rates are classified as low (less than 12,470 volts), medium (between 12,470 and 138,000 volts) and high (more than 138,000 volts). The primary customer class in COSS includes Cp-1, Cp-3, Cp-3S, Cp-FN and market-based rates.

Q. Please describe the energy rates for the CP rate classes.

A. Historically, the energy rates have been set at the same level for all the CP rate schedules. In Docket 05-UR-107, Order Point 30 directed WEPCO to work with WIEG, other interested stakeholders, and Commission staff to evaluate electric cost of service with respect to the seasonality of its costs, and to develop and submit a seasonally differentiated electric rate design proposal in its next base rate case.

Q. What has WEPCO done to comply with Order Point 30?

A. WEPCO worked with WIEG to develop summer/non-summer demand and energy ratios for the Company's proposed rate design.

As a first step, WIEG and the Company agreed to introduce these seasonal rate differentials for the Cp-1 Primary TOU rate and, in the interest of gradualism and to avoid rate shock, to phase seasonal differentials into other tariffs over time. Because the evaluation was done prior to this rate case, the cost of service study from Docket 05-UR-107 was used for the analysis during those discussions.

Q. How did WEPCO address seasonal relationships for energy charges?

A. WEPCO and WIEG agreed to use LMP relationships to differentiate on-peak summer and non-summer energy rates. Historical summer on-peak to non-summer on-peak ratios, based on on-peak hours for the CP Primary TOU hours and the MISO real time LMPs at the WEC.S load node, are shown below.

Historical On-Peak Ratios (Summer to Non-Summer)			
Years	Avg. Summer LMPs	Avg. Non-Summer LMPs	Ratio
2014	41.21	47.13	0.87
2015	31.82	29.27	1.09
2016	36.19	28.51	1.27
2017	38.70	30.53	1.27
2018	38.58	33.21	1.16
5 Year Avg. (2014-2018)	37.30	33.73	1.11
4 Year Avg. (2015-2018)	36.32	30.38	1.20
3 Year Avg. (2016-2018)	37.82	30.75	1.23
2 Year Avg. (2017-2018)	38.64	31.87	1.21

*Based on WEC.S Real Time LMPs and CP Primary TOU Rate Hours

Q. What energy rate differential is WEPCO proposing for the Cp-1 Primary TOU rate schedule?

A. WEPCO is proposing a 15% differential for the seasonal energy rate for this tariff. The actual ratio ranged from 0.87 to 1.27 in the last five years. A 15% differential will be a first step toward a seasonal rate adjustment and can be revisited in the next rate case.

Q. What energy charges is WEPCO proposing for the CP rate schedules?

A. Comparing current revenues to 2021 revenues, WEPCO is proposing an overall decrease of approximately 7.8% for the on-peak energy charges and less than a 1% increase to the off-peak charges. This results in an overall 3.5% decrease in revenue collection from energy charges, which is a step toward COSS. The energy levels for the Cp-1 Primary TOU rate schedule are differentiated by season, with the Cp-3, Cp-3S, and Cp-FN rate schedules set at the same levels but on an annual basis.

Q. How did WEPCO address seasonal relationships for demand charges?

A. The Company presented WIEG with two scenarios. One scenario set the non-summer demand charges at 20% of the current charge and another scenario set the non-summer demand charges at 50% of the current charge, with both scenarios maintaining the same level of demand revenues. To minimize bill impacts, WEPCO

accepted WEIG's recommendation to set the non-summer rates at approximately 88% of the current demand charge, which results in a summer to non-summer ratio of 139%. This differential is close to WEPCO's summer/non-summer system peak load differentials. WEPCO is a summer peaking utility with an average summer system peak in 2018 of 5,344 MWs and a non-summer peak of 4,015 MWs.

Q. What changes is WEPCO proposing to the customer demand charge?

A. The Company is proposing to increase this charge to $2.50/kW in TY 2020 and to $2.75/kW in 2021. This compares to a COSS recommendation of $3.27/kW. With these adjustments, WEPCO will collect less than one percent more than the COSS-recommended distribution charges.

Q. Is WEPCO proposing any changes to the curtailable credits in Cp-3, Cp-3S or Cp-FN?

A. No. WEPCO is proposing to maintain these credit levels.

Q. What is the overall impact of these changes on the CP primary rate schedules?

A. The overall rate increase for the CP rate schedules is 3.13% for TY 2020 and 1.97% for 2021. This rate increase results in final test year revenue of $607,420,066 compared to the COSS-indicated revenue requirement of $611,598,224.

<u>Customer-Owned Generation</u>

Q. Please describe WEPCO's current customer-owned generation tariffs.

A. The Company currently has twelve customer-owned generation tariffs. Eight of these are closed to new customers, seven of which also have defined tariff or contract expiration dates. These tariffs and their participation rates are shown on the following page:

Closed Customer-Owned Generation Tariffs					
Tariff	**Load**	**No. of Customers**	**Tariff Expires**	**Generator Size**	**Buy-back Rate ($/kWh)**
CGS-1	Netted	37	12/31/2024	>20 kW	Average DA LMP
CGS-2	Netted	40	12/31/2024	≤20 kW	Retail Rate
CGS-3	Emergency Capacity Tariff	1	NA	≥300 kW	Varies
CGS-4	Netted	11	Last Contract Expires April 2022	Wind >20 kW, ≤100 kW	Retail Rate
CGS-5	Not Netted	6	Last Contract Expires April 2028	Biogas ≤2,000 kW	On Peak: $0.1550 Off Peak: $0.0614
CGS-6	Netted	335	12/31/2024	≤20 kW	Retail Rate
CGS-8	Netted	171	12/31/2024	≤20 kW	Flat Rate: $0.04245 On Peak: $0.04982 Off Peak: $0.03849
CGS-PV	Not Netted	28	Last Contract Expires June 2022	Solar PV >1.5 kW, ≤100 kW	All kWh: $0.225

DA = Day Ahead
LMP = Locational Marginal Price
Closed = Closed to new customers
Netted = Load netted with generation

The Company has four customer-owned generation tariffs open to new customers. These tariffs are summarized on the following page:

Open Customer-Owned Generation Tariffs					
Tariff	**Load**	**Metering**	**No. of Customers**	**Generator Size**	**Buy-back Rate ($/kWh)**
CGS-NM	Netted	Gen. Meter and Load Meter (Order Point 31 05-UR-107)	662	<300 kW	LMP Based
CGS DS-FP	Not Netted	Gen. Meter and Load Meter	2	<2,000 kW	LMP Based
CGS DS-VP	Not Netted	Gen. Meter and Load Meter	0	>2,000 kW, ≤15,000 kW	Average DA LMP
CGS-NP	Netted	Gen. Meter and Load Meter (Order Point 31 05-UR-107)	32	< 15,000 kW	Non-Purchase Tariff

*Customer counts as of December 31, 2018.

Q. Please explain Order Point 31 from Docket 05-UR-107.

A. Order Point 31 directed WEPCO to install meters capable of measuring the actual output capacity, on an interval basis, of generating systems under CGS-NM and CGS-NP. WEPCO was ordered to bear the cost of the new meters.

Q. How did the Company address Order Point 31?

A. The Company installed interval meters on newly enrolled CGS-NM and CGS-NP generators, with one exception. In October of 2016, the Company received a waiver from the Commission for situations that required more than three meters to isolate the generator output (PSC REF # 292776).

Q. Please explain Order Point 32 from Docket 05-UR-107.

A. Order Point 32 directed WEPCO to perform a true-up at the end of 2016 to address any difference between the metered monthly maximum generation capacity of customers enrolled under CGS-NM or CGS-NP and the rated nameplate capacity of their systems. The Commission ordered this analysis because the demand charge approved for these tariffs in the same docket was based on rated nameplate capacity and some argued this was an inappropriate proxy for the actual amount of energy a customer generates.

Q. How did the Company address Order Point 32?

A. Because the demand charge that was approved for the CGS-NM and CGS-NP tariffs was overturned on appeal, the true-up was no longer necessary. However, as I discuss next, we still collected the data that would have been necessary for the true-up.

Q. Please describe Order Point 33 from Docket 05-UR-107.

A. Order Point 33 directed WEPCO to present the data collected by demand meters in its next full rate case so the Commission could evaluate whether the COGS capacity demand charges approved in that docket, and the basis for determining the billing units for those charges, were appropriate or required modification. Based in part on these data, WEPCO now proposes a somewhat different approach to the same end: a modest step toward ensuring that generation-owning customers contribute their fair share towards the fixed costs of connecting them to WEPCO's distribution system and providing them with service up to their peak load whenever they need it. I will discuss this proposal in greater detail after presenting the data we gathered.

Q. Please describe the types and number of customers subject to Order Point 33.

A. The population of relevant customers is summarized in the table on the following page. The customer counts in each column represent new additions in that year.

	Total Interval Metered CGS-NM and CGS-NP Customers			
Rate Description	**2015**	**2016**	**2017**	**2018**
Residential Standard	62	118	139	203
Residential Time of Use	14	17	18	17
Commercial Non-Demand	8	3	10	12
Commercial Demand	5	15	11	10
Total	**89**	**153**	**178**	**242**

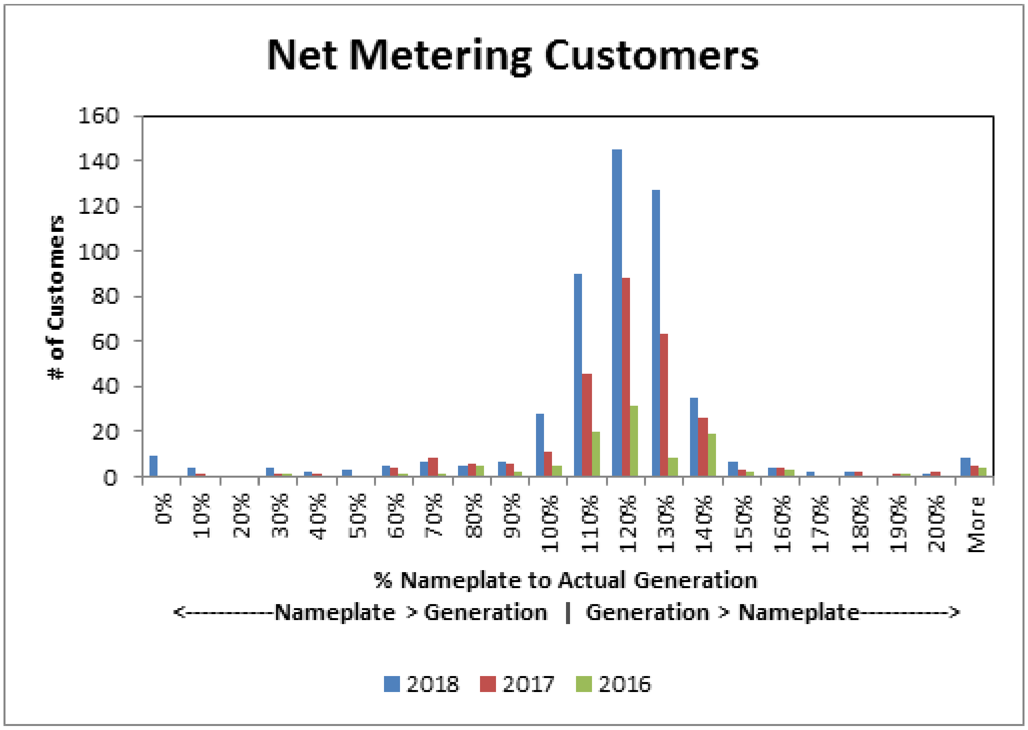
*Includes customers that had 365 days of consumption for each specific year.

Q. Please describe the customer interval data and how it compares to generator nameplate capacity ratings.

A. The installed generation on the CGS-NM tariff is all solar generation. A direct comparison between nameplate capacity and actual generation is not possible because the nameplate capacity of the solar generation is stated in direct current (DC) and the generator output from the customer's inverter is measured in alternating current (AC). To compare the generator output to the generator nameplate capacity, we converted the DC rating to AC by applying an inverter efficiency factor of 0.77, an average calculated by the National Renewable Energy Laboratory and specified in the CGS-NM tariff.

Q. How does actual peak demand in AC compare to the generator nameplate capacity converted to AC?

A. The majority of the generators we measured produced between 100% and 150% of their nameplate capacity. Below is a graph that illustrates the results by year. In this graph, if the percentages are lower than 100%, the generator produced less than the nameplate capacity. If the percentages are greater than 100%, the generator produced more than the nameplate capacity. For example, in 2018, 145 customers had generators that produced between 110% and 120% of the generator nameplate capacity, when converted to AC.



Q. Is there a more appropriate factor for converting the generator nameplate (DC) to the generator output (AC)?

A. Potentially, but with our enhanced ability to measure generator output, it would be more reasonable to base fixed cost recovery on actual metered output going forward. Customers could achieve better efficiency than the 77% inverter efficiency factor we assumed by investing in a higher efficiency inverter, using battery storage, or aligning generation with consumption. Because of the multiple contributors to the range of the generator's measured output, and because we are now able to directly measure customer-specific generator output, the Company is recommending that the actual measured generation output be used to assess charges intended to recover fixed costs of service.

Q. Is Wisconsin Electric proposing any changes to its net metering tariffs?

A. Yes. The Company continues to pursue net metering rates that more closely follow the fundamental principle of cost causation: that customers should pay approximately what it costs the utility to serve them. This year, we are proposing a new charge for our two open net metering tariffs, CGS-NM and CGS-NP, to better align rates with costs. Our proposed Fixed Cost Recovery Charge ("FCRC") is designed to recover a small portion of the fixed costs CGS customers avoid paying when they generate their own power. Because WEPCO currently collects a substantial portion of its fixed cost of serving smaller customers through its volumetric energy rates, customers who generate their own energy avoid paying some of these fixed costs. The proposed FCRC takes a modest correctional step by recovering a portion of these costs through a charge based on the customer's average monthly peak generation.

Q. How is CGS-NM structured currently?

A. CGS-NM is a voluntary net metering tariff that allows customers not only to offset their electricity consumption with their own generation, but also to sell excess generation back to the Company at a buy-back rate based on locational marginal prices (LMPs). Customers taking service under this tariff have two meters: one for generation (which measures the energy the customer produces) and one for load (which measures the energy the customer uses). The tariff is limited to customer-owned generators smaller than 300 kW, and 662 customers were on the tariff as of December 31, 2018.

Q. What types of customers take service under the CGS-NM tariff?

A. Most of our CGS-NM customers are residential customers who would otherwise take service under Rg-1, our standard energy-only residential tariff, with smaller generation systems (typically under 20 kW). But a number of our CGS-NM customers fall into the commercial class, with larger generation systems (up to the 300 kW tariff limit), and would otherwise take service under one of our demand and energy tariffs.

There are exceptions; for example, some residential customers may have larger generation systems, and some commercial customers may take service under an energy-only rate. The table below shows the breakout of CGS-NM generation capacity by customer type. For present purposes, I will distinguish between CGS-NM customers on an energy-only rate (the first three rows of the table) and CGS-NM customers whose tariff includes a demand charge (the last row of the table). Our proposed FCRC would apply to the first group; for the second group, we propose a new standby charge that I will discuss later.

CGS-NM Customer Generation Capacity						
	Generation Capacity (kW)					
Customer Type	**<10**	**10 - 19**	**20 – 29**	**30 - 39**	**40 - 49**	**>50**
Residential & Farm Flat (Rg-1, Fg-1)	468	47	3	1	0	3
Residential TOU (Rg-2)	55	11	0	0	0	0
Commercial Energy Only	14	8	2	3	2	4
Commercial Demand & Energy	1	1	2	1	2	34

Q. How are current rates structured for CGS-NM customers on energy-only rates?

A. Under the current rates, these customers purchase any net energy they use at the volumetric retail rate applicable to their class (again, for ordinary residential customers, Rg-1). They also pay the same monthly facilities charge as other customers in their class. However, unlike the other customers in their class, they do not pay all of the fixed costs that the utility incurs to provide them a reliable energy infrastructure whenever they need it—24 hours a day, 7 days a week, 365 days a year—to purchase energy from the utility or sell energy they generate to the utility.

Q. Why is that?

A. This is a result of WEPCO's current, traditional electric rate design for smaller customers. Because the Company's volumetric energy rates recover a large portion of the Company's fixed costs of service, customers who offset a portion of their load

with their own generation avoid paying some of the fixed costs that the Company incurs to serve them. For example, if a customer offsets all of their load with their own generation, their bill can be just the fixed monthly facilities charge. They wouldn't pay any energy charges because they have offset all of their load with generation, avoiding (but not reducing) all the fixed costs that are recovered in the energy rate.

Q. Do you have data on the cost to serve customers who own generation?

A. Yes. Like any public utility, WEPCO has the important obligation of providing a fully functioning electric generation, transmission, and distribution system sized to meet the peak demand of *all* of its customers, including those who own their own generation, plus a reserve margin. We know what it costs to provide that system because we complete very detailed cost and sales forecasts and a COSS as the basis for our request to adjust electric rates. My colleague Aaron Nelson describes WEPCO's COSS in his direct testimony.

Q. Does the COSS provide information on the costs of serving each class of customers?

A. Yes. As Mr. Nelson explains, we use fairly complex, Commission-approved allocation methodologies to ensure that our COSS appropriately apportions total costs of service to the various customer classes (residential, industrial, commercial, and so on) based on the principle of cost causation. Although competing policy considerations may sometimes justify departing from basing rates purely on COSS, our proposed rate design reflects our best effort to reasonably apportion costs to the customers causing them, taking into account the various rate design factors I identified at the beginning of my testimony.

Q. What does the COSS tell us about the Company's fixed and variable costs?

A. We know that the majority of the Company's costs of service are fixed, by which I mean they are required to provide service to customers regardless of how much energy they use. These include the costs of building and maintaining the utility's

infrastructure (power plants, transmission lines, substations, and distribution lines). They also include a host of business-related costs, like labor, vehicles, insurance, and the utility's billing, administrative, and customer services function—in layman's terms, "overhead." A smaller portion of the Company's costs are variable, meaning they increase or decrease with energy consumption. The primary example is the fuel we use to power our non-renewable generation plants.

The relationship between fixed and variable costs is fairly lopsided. For example, our COSS tells us that of all the costs to serve our residential customers, 78% are fixed and only 22% are variable. While there may be room for debate about exactly what proportion of overall costs are fixed, there can be little debate that the fixed costs of providing residential and small commercial electric service are much greater than currently reflected in the monthly facilities charge that these customers currently pay.

Q. How do fixed and variable costs relate to customer rates?

A. When we design rates, we have choices to make about how to recover our fixed and variable costs. One way to do this would be to take all of our fixed costs, divide them by our total number of customers, and have each customer pay an identical share of our fixed costs. This would leave only our variable costs to be recovered through a volumetric charge, *i.e.*, a charge based on how much energy each customer uses. However, this would result in higher fixed monthly charges unrelated to energy use. Historically, electric rates have been designed to recover a significant portion of the utility's fixed costs through the volumetric charge in order to provide a stronger incentive for customers to conserve their use of energy. Thus, in our tariffs for residential and small commercial customers, the monthly facilities charge recovers only *some* of our fixed costs, and the volumetric charge based on energy usage recovers both our variable costs *and* the remaining fixed costs not recovered by the monthly facilities charge.

Q. How does this play out in the context of a specific tariff?

A. I will use our primary residential tariff, Rg-1, as an example because most of our CGS-NM customers are taking service under that tariff. If we were to set the Rg-1 facilities charge at the level necessary to capture all of our fixed costs, it would be considerably higher than the $17.65 per month proposed in this case. Because the facilities charge recovers only a portion of our fixed costs, we need to recover all of the remaining fixed costs through the volumetric energy charge, which still needs to recover all of the Company's variable costs, as well.

Q. What are the full costs of serving a standard residential customer per COSS?

A. The fixed and variable costs are shown on Schedule 30 of Ex.-WEPCO WG-Nelson-7. The costs are broken down on an energy basis on line 6. At lines 8-10, Mr. Nelson's exhibit allocates these costs to the residential class and shows how they would be recovered in rates if the Company had a more sophisticated rate design for residential customers, similar to the rate design of a large industrial customer:

Rg-1 COSS Results			
Service Provided	**Cost in $/kWh (Line 6)**	**Appropriate Charge (Lines 8-10)**	**Type of Cost**
Customer-Related	$0.03160	$0.64/day	Fixed
Distribution Demand	$0.03033	$7.74/kW	Fixed
Transmission Demand	$0.01693	$7.38/kW	Fixed
Transmission Energy	$0.00030	$0.00030/kWh	Variable
Production Demand	$0.05636	$24.57/kW	Fixed
Production Energy	$0.03677	$0.03677/kWh	Variable
Total	**$0.17229**		

*$/MWh converted to $/kWh

Q. How do these concepts relate to net metering customers?

A. In most respects, customers on the CGS-NM tariff are just like any other customers in their class. But for their ability to offset some of their consumption with onsite generation (and, in some cases, deliver excess generation back to the grid), they

take service under the same tariff as their neighbors (again, typically Rg-1) whenever they purchase energy from WEPCO, reflecting the fact that the same power grid (with the same costs) exists to serve all of them.

However, CGS-NM customers are different from their neighbors in one key respect: when they avoid purchasing energy by generating it themselves, they avoid paying some of the fixed costs that their neighbors are paying as part of their energy rate. For example, consider two neighbors, one with solar panels and one without, who both consume 1,000 kWh of electricity in an average month. Although both rely equally on the electric grid all month long for service up to their peak loads, and although the utility must size its system to serve both of their peak loads, the solar customer will not pay the same share of the fixed costs of that system as her neighbor will. Instead, under WEPCO's proposed rates, if that customer generates 600 kWh of electricity in an average month, she will avoid not only our variable costs of providing that energy to her (which is appropriate), but also 60% of the fixed costs her neighbor is paying for the same system.

If these differences persist across an entire class of customers, the result will be that the total difference needs to be made up somewhere. If and to the extent a portion of WEPCO's residential CGS customers avoid contributing their share of the fixed costs allocated to the customer class, the costs must be collected from the other, non-generating customers in the class. Customers without their own generation will end up subsidizing their CGS-NM neighbors.

Q. Is Wisconsin Electric proposing the FCRC to address these issues?

A. Yes, precisely. For energy-only customers with generation up to 300 kilowatts—the majority on the CGS-NM tariff—we propose a new fixed cost recovery charge or "FCRC" of $3.53 per kilowatt of monthly peak generation to capture some of the fixed costs these customers avoid paying when they self-generate.

Q. How would the new FCRC proposed for CGS-NM customers work?

A. In a given month, CGS-NM customers would continue to pay the same facilities charge as their neighbors, as well as the same volumetric rate for the net energy they consume. In addition, they would be subject to the FCRC, which would apply to the actual monthly peak output of their generation system. The FCRC would commence January 1, 2021 for CGS-NM customers.

Q. What is your estimate of the average CGS-NM customer's generator output?

A. Thanks to the meters installed pursuant to Order Point 31 in Docket 05-UR-107, the Company has metered generation output data for customer generation installations for every hour. Using data from the 440 customers that had 365 days of data in 2018, we calculated the annual production from the customer generation. On average, these customers generated 1,229 kWh per year for each kW of installed capacity. This equates to an approximate 14% capacity factor for the CGS-NM customers. We used these figures to derive the FCRC, as I will explain in greater detail in a moment.

Q. Please explain what costs are included in the FCRC.

A. The charge is designed to recover two cost components corresponding to the first two rows of the table on page 27 of my testimony: (1) the customer-related distribution costs that are not collected in the facilities charge and (2) the distribution demand costs, both at a class-specific level as shown in the COSS. I will first walk through how we used the COSS to calculate the costs to be recovered in the FCRC for the residential and farm rate classes. After that, I will explain how we translated these costs ($/kWh) into the FCRC ($/kW/month).

<u>Step 1 - Calculate customer-related costs not recovered in the facilities charge</u>:

The first step is to identify the total customer-related distribution costs that are allocated to the Rg-1, Fg-1 and Rg-2 rate schedules. Because some of these costs are recovered through the daily facilities charge that customers already pay, the FCRC would include only the customer-related distribution costs that are *not* already

collected through the facilities charge. This difference is then divided by the forecasted annual energy consumption for these rate schedules:

Customer-Related Distribution Costs		
Rg-1, Fg-1	(COSS, Sched. 30, Col. I, line 4)	$237,509,848
Rg-2	(COSS, Sched. 30, Col. I, line 12)	$ 4,178,188
Total		$241,688,036

Facilities Charge Revenues in 2021 Proposed Rates	
Rg-1, Fg-1	$213,769,804
Rg-2	$ 3,427,650
Total	$217,197,454

Customer-Related Distribution Costs not Collected in Facilities Charge ($)	
Customer-Related Distribution Costs	$241,688,036
Facilities Charge Revenues in 2021 Proposed Rates	$217,197,454
Difference	$ 24,490,582

Customer-Related Distribution Costs not Collected in Facilities Charge ($/kWh)	
Customer-Related Distribution Costs not Collected ($)	$24,490,582
Rg-1, Fg-1, Rg-2 Energy (kWh)	7,741,019,654
Costs not recovered on a $/kWh basis:	**$0.00316/kWh**

Step 2 – Calculate total distribution costs:

The second step is to calculate the total fixed distribution costs for the Rg-1, Fg-1, and Rg-2 rate schedules. This is done by isolating the distribution demand costs allocated to customers under those rate schedules and adding them to the customer-related distribution costs not collected in the fixed charge, on a $/kWh basis.

Distribution Demand Costs		
Rg-1, Fg-1	(COSS, Sched 30, Col H, line 4)	$227,952,827
Rg-2	(COSS, Sched 30, Col H, line 12)	$ 4,269,816
Total Distribution Demand Costs		$232,222,643

Distribution Demand Costs	
Total Distribution Demand Costs	$232,222,643
Rg-1, Fg-1, Rg-2 Energy (kWh)	7,741,019,654
Costs not recovered on a $/kWh basis:	$0.03000/kWh

Total Distribution Costs	
Remaining Customer-Related Distribution Costs	$0.00316/kWh
Distribution Demand Costs	$0.03000/kWh
Total Distribution Costs	**$0.03316/kWh**

Q. Based on that calculation, what annual distribution costs would a customer who installs a 1 kW solar generation system avoid paying under the Company's proposed rates?

A. As I have explained, an average customer with a 1 kW solar installation would generate 1,229 kWh on an annual basis. Under the current net metering methodology, this 1,229 kWh would be netted or subtracted from their consumption assuming the consumption at the premises exceeded the solar generation each month. Multiplying the $0.03316/kWh of distribution costs that are being recovered in the energy charge by the 1,229 kWh equals $40.75 per year. This amount represents the annual distribution costs avoided (but not reduced) by a net metering customer with a 1 kW solar installation.

Q. How does WEPCO propose to recover this $40.75?

A. One way would be to divide $40.75 by 12 to derive a monthly amount and then bill net metering customers this monthly amount times the nameplate capacity of their generation system in kilowatts. As I have discussed, however, our new meters allow us to treat customers on an individual basis, and the data we have already collected shows that a customer's actual monthly generation may differ from nameplate capacity in either direction. For these reasons, we are recommending that the FCRC be assessed on the actual peak monthly output of the customer's generation system. To do this, we first had to convert the $40.75 in annual distribution costs into a per-kilowatt charge that accounts for the relationship between nameplate capacity and monthly peak generation.

Q. How did you do that?

Once again using data from our customer solar generation installations, we divided total metered monthly peak generation by total nameplate capacity. This step of the calculation recognizes that a 1 kW solar system does not generate a peak of 1 kW every month, but something less in most months. The twelve monthly peaks would

therefore total less than 12 kW per year. The following table summarizes the monthly peaks seen in our data, which add up to 11.55 kW of annual peak production.

January	0.831 kW
February	0.977 kW
March	1.075 kW
April	1.034 kW
May	1.045 kW
June	1.030 kW
July	1.026 kW
August	0.999 kW
September	0.992 kW
October	0.925 kW
November	0.837 kW
December	0.779 kW
Total	11.550 kW

Q. How is the proposed $3.53/kW/month FCRC calculated?

A. To recover the $40.75 of annual distribution costs that a customer with a 1 kW solar generating system avoids paying in current rates, we divided $40.75 (annual cost) by 11.55 kW (annual peak production) to arrive at the FCRC of $3.53 per kilowatt of monthly peak generation.

Q. Have you calculated a specific FCRC for commercial energy-only customers?

A. Yes. Using the same methodology as for the residential customers, the FCRC for commercial energy-only customers equates to $3.67/kW. This calculation uses an average annual generation of 15,557 kWh, and an average system capacity of 13.99 kW. Thus, for each 1 kW of installed capacity, these customers would be generating 1,112 kWh. As shown on Schedule 10 of Ex.-WEPCO WG Ferguson-1, the distribution costs not collected in the energy charge equate to $0.02272/kWh or $25.26 per month. Dividing by the annual distribution demand of a 1 kW system (6.89 kW, per the peaking methodology explained previously for residential customers), the FCRC for the commercial energy-only customer comes to $3.67/kW.

Q. Please illustrate what a theoretical residential customer with a 1 kW distributed generation system would pay under the FCRC.

A. The FCRC would only be assessed on the customer's actual, metered peak

generation each month, not the nameplate capacity of their system, so a year's worth of generation following typical peaks would result in the following charges:

Month	Peak Generation	FCRC	Monthly Charge
January	0.831 kW	$3.53	$2.93
February	0.977 kW	$3.53	$3.45
March	1.075 kW	$3.53	$3.79
April	1.034 kW	$3.53	$3.65
May	1.045 kW	$3.53	$3.69
June	1.030 kW	$3.53	$3.64
July	1.026 kW	$3.53	$3.62
August	0.999 kW	$3.53	$3.53
September	0.992 kW	$3.53	$3.50
October	0.925 kW	$3.53	$3.26
November	0.837 kW	$3.53	$2.95
December	0.779 kW	$3.53	$2.75
Total	11.55 kW		$40.76

Q. What is the average size of solar installations for the Rg-1, Fg-1 and Rg-2 rate schedule?

A. Using the 2018 data from the 440 customers that had 365 days of data, the average size photovoltaic installation is 4.43 kW, with an average peak output of 4.25 kW.

Q. Please provide a billing comparison for a typical solar customer taking service under the CGS-NM rate.

A. The table below compares an average net metering customer with solar generation being billed (1) without any generation, (2) using the current netting methodology, and (3) with the proposed FCRC.

Example: Solar Generation Customer Bill							
Billing Charges		Solar Customer without Generation		Solar Customer with Generation (Current Netting)		Solar Customer with Generation (Current Netting + FCRC)	
Charge	Unit Charge	Billing Units	$	Billing Units	$	Billing Units	$
Facilities	$0.57885 / day	30 days	$17.65	30 days	$17.65	30 days	$17.65
GFC	$0.05951 / day	30 days	$1.79	30 days	$1.79	30 days	$1.79
Energy	$0.14406 / kWh	851 kWh	$122.60	397 kWh	$57.19	397 kWh	$57.19
FCRC	$3.53 / kW	N/A	N/A	N/A	N/A	4.25 kW	$15.00
Total			$142.04		$76.63		$91.63

As the chart indicates, the customer in this example will still realize a significant savings from participating in net metering ($50 per month), but will contribute slightly more ($15.00 per month) towards distribution costs than under current rates.

Q. Have you attempted to verify that the Company's distribution costs to serve the residential class are not reduced by customers with generation systems?

A. Yes, our analysis shows that our costs of providing distribution service to a class do not differ based on whether customers within that class own self-generation systems.

Q. Why is that?

A. WEPCO's distribution system is designed to meet its customers' peak demands. From the data collected from residential customers with generation, we found that these customers' average monthly peak demand was not reduced materially after they installed generation:

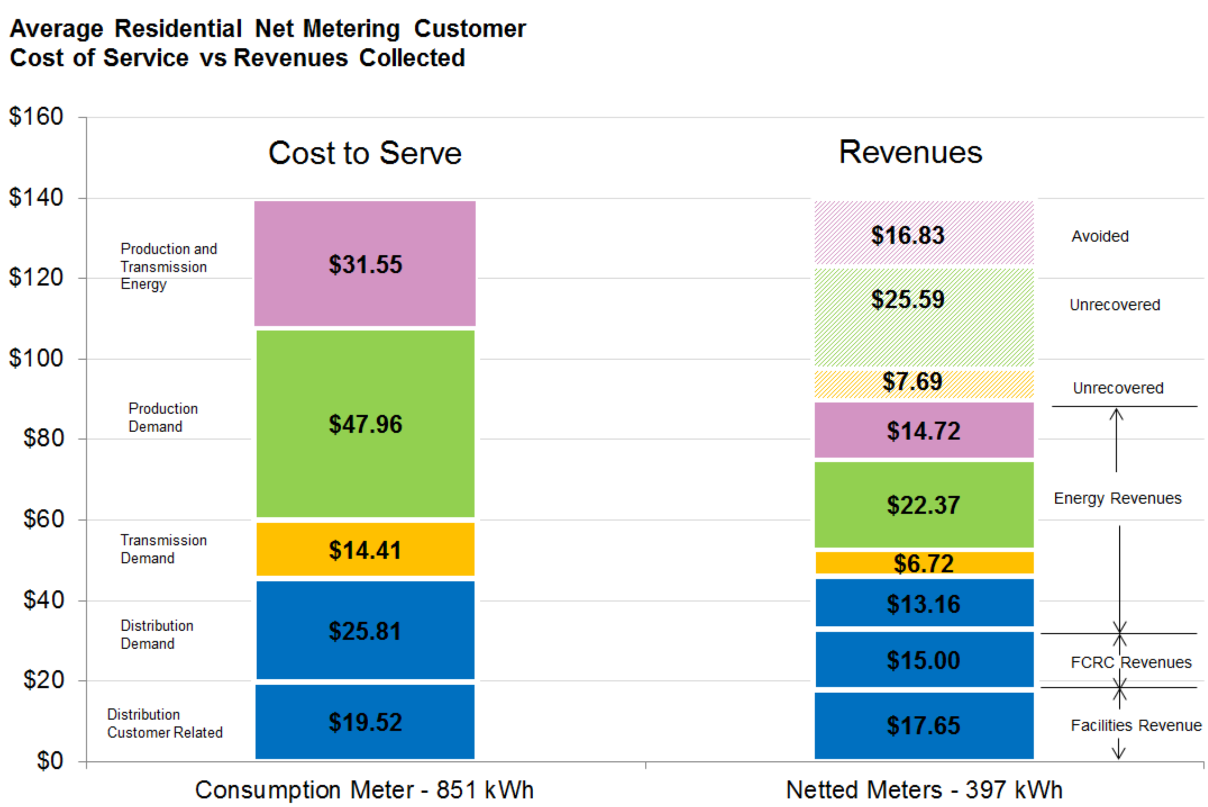
Month	**Peak kW Consumption**	**Peak kW Net**
January	6.72	6.55
February	6.70	6.60
March	6.69	6.42
April	5.99	5.67
May	7.01	6.53
June	7.63	7.10
July	7.61	7.05
August	7.28	6.82
September	6.95	6.56
October	6.51	6.34
November	6.90	6.77
December	6.95	6.84
Average	6.91	6.60

This is because customer-owned generation is intermittent, and the generation-owning customer must still purchase 100% of their requirements from the utility when their generation is not operating. For instance, on a hot summer day, solar panels may reduce the customer's peak load during the day, but our system must be sized to serve all of that customer's load once the sun goes down that night. In the table below, we can see that the customer's metered peak monthly consumption (the greatest load they place on the system that month) is virtually identical to the peak

net of their load and generation in the same period. That is, regardless of any self-generation offset reflected in the second column, we still must size our distribution system to meet the peak load in the first column, and in any given month the two end up being roughly the same.

Q. If implemented, will the FCRC ensure that Wisconsin Electric recovers all of its fixed costs from CGS-NM customers?

A. No, not even close. As the figure below indicates, this charge is calculated to recover just one of several fixed cost components included in the volumetric energy charge and thus not recovered from net metering customers when they offset load. Again, based on our COSS, it would require significant monthly fixed charges to recover those costs fully on a fixed basis. By comparison, the FCRC we are proposing is relatively modest; in our view, it is a step towards appropriate rate-setting based on the principle of cost causation.



Q. What does this figure represent?

A. The column on the left represents the full monthly cost of providing service to an Rg-1 customer with an average consumption of 851 kWh per month. According to the COSS for the 2020 test year, these costs total $139.25. Broken out by functional component, they are as follows:

Distribution customer-related costs (Schedule 31, COSS)		$19.52
Distribution Demand (Schedule 30, COSS)	$0.03033 * 851 kWh =	$25.81
Transmission Demand (Schedule 30, COSS)	$0.01693 * 851 kWh =	$14.41
Production Demand (Schedule 30, COSS)	$0.05636 * 851 kWh =	$47.96
Production Energy	$0.03677 * 851 kWh =	$31.29
Transmission Energy	$0.00030 * 851 kWh =	$00.26
(Schedule 30, COSS)		$31.55
Total Cost:		**$139.25**

The column on the right represents the revenues that the average Rg-1 customer with a 1 kW solar installation would pay to WEPCO under its proposed rates for 2021. These rate components include:

Facilities Revenue:	$0.57885/day * 30.5 days	$17.65 per month
Energy Revenue:	$0.14406/kWh * 397 kWh	$57.19 per month
FCRC Revenue:	$3.53/kW * 4.25 kW peak generation	$15.00 per month
Total Bill:		**$89.84 per month**

Assuming net consumption of 397 kWh and self-generation of 454 kWh, these revenue components may be correlated with the cost components above as follows:

Functional Cost	Revenue Type	Billing Unit	Charge	Total
Distribution	Facilities Charge	1 month	$17.65 / month	$17.65
Distribution	FCRC	4.25 kW	$3.53 / kW	$15.00
Distribution	Energy Rate	397 kWh	$0.03316 / kWh	$13.16
Transmission Demand	Energy Rate	397 kWh	$0.01693 / kWh	$6.72
Production Demand	Energy Rate	397 kWh	$0.05636 / kWh	$22.37
Prod. & Trans. Energy	Energy Rate	397 kWh	$0.03707 / kWh	$14.72
Transmission Demand	Unrecovered	454 kWh	$0.01693 / kWh	$7.69
Production Demand	Unrecovered	454 kWh	$0.05636 / kWh	$25.59
Prod. & Trans. Energy	Avoided	454 kWh	$0.03707 / kWh	$16.83

Q. What does this comparison of costs and revenues illustrate?

A. It shows that even after implementing the FCRC as proposed, the average Rg-1 solar customer will pay approximately $50 less per month than an identical customer without generation, a savings of 11 cents per kWh of self-generated energy. The savings are shown at the top of the column on the right, and are comprised of two cost components:

Roughly a third of the amount ($16.83) represents variable energy production and transmission costs that the CGS customer arguably allows the utility to avoid by purchasing less energy ("Avoided Energy Costs"). It is appropriate to credit these savings to the CGS customer, and the customer receives that credit—and then some—when we net their generation against their load.

The rest of the shortfall ($33.28) represents fixed production costs ($25.59) and transmission costs ($7.69) that this customer would *not* help the utility avoid, but will avoid paying by avoiding the volumetric energy charge even after paying the proposed FCRC ("Unrecovered Fixed Costs"). The Company has elected not to address these costs at this time in the interest of gradualism in rate design. While there is strong cost support for requiring CGS customers to pay most if not all of these fixed costs, at this time we do not propose going beyond the FCRC.

Q. How does the proposed FCRC relate to the CGS demand charge that WEPCO proposed and the Commission approved in Docket 05-UR-107?

A. The basic concept is the same; namely, the charge is intended to recover some of the fixed costs that generation-owning customers avoid paying (but not causing) when they avoid paying the utility's volumetric energy charge. But there are several differences that make the FCRC a superior method of accomplishing this modest step.

First, we now have the benefit of both consumption and output data from the second meters installed for customers who have installed solar generation. These data provide a stronger factual basis for *designing* a fixed cost recovery charge by confirming that customers who own solar generation systems have nearly identical monthly peak demands as they did before their generation was installed. That is, these customers place similar demands on the local distribution system with or without their own generation. It is therefore reasonable to recover distribution costs from them as we do from their non-generating neighbors in the same class.

A second difference is that the Company proposes to *bill* the FCRC using actual meter data as opposed to nameplate capacity. Using metered data provides a more accurate way to charge the FCRC to individual customers. As a result of this change, if two customers have the same size generation system but one generates a lower peak in a given month, she will pay a lower FCRC in recognition of the fact that she contributed more to fixed costs than the customer who generated more.

Third, we have provided a transparent, step-by-step calculation of the FCRC, showing exactly how it recovers class-specific costs identified in WEPCO's COSS through a charge based on metered data from customers with solar generation.

Q. What do you propose for customers billed on demand rates that have their own generation?

A. For these customers, we are proposing that new customers pay a standby rate similar to the one the Commission has approved for WPSC's distributed generation customers. Based on the COSS submitted with Mr. Nelson's direct testimony, we will discuss standby rate design options with these customers and file a proposed design in supplemental testimony, with existing customers to be grandfathered through December 31, 2028. This proposal is consistent with Order Point 34 from Docket 05-UR-107, which directed Wisconsin Electric to develop a standby rate proposal with affected customers and present that proposal in its next full rate case.

Q. Does Wisconsin Electric propose changing the buyback methodology or monthly netting period for CGS-NM?

A. Not at this time. However, now that we have installed the new meters ordered by the Commission, we have the ability to net CGS-NM customers' production and consumption on an hourly basis, and may propose doing so in the future.

Q. When does Wisconsin Electric propose phasing in these charges?

A. To allow time for billing implementation, we would propose to delay the new CGS-NM charges until January 1, 2021.

Q. Is Wisconsin Electric proposing the same changes to its CGS-NP tariff?

A. Yes. The only material difference between the CGS-NM and CGS-NP tariffs is the absence of a buyback rate: customers on the CGS-NP (non-purchase) rate are not compensated for their generation. These customers can still offset some or all of their own load and avoid paying the fixed cost of distribution to that extent.

Q. Are there other ways Wisconsin Electric could address the disconnect that occurs when fixed costs are recovered in variable charges?

A. Yes. To take one example, the Company could unbundle the energy rate for energy-only rate schedules, with distribution-related costs charged separately for all

customers and not netted (that is, not credited) for net metering customers. This approach was proposed by Commission Staff in Docket 05-UR-107.

Q. What does unbundling mean and what are its benefits?

A. Unbundling simply means separating the current volumetric energy rate into two distinct charges that would be listed separately on customers' bills. Traditionally this takes the form of a delivery charge and an energy charge. The delivery charge would include customer- and distribution-related costs not covered in the facilities charge, as well as transmission system costs. The energy charge would include costs to produce the energy the customer uses.

Relative to current rates, non-generating customers would not pay any more or less for energy under unbundled rates, as the sum of the new delivery and energy charges would be designed to equal the former energy charge. But the new bill structure would improve transparency, providing customers with better information about how each component of their rate relates to the utility's costs of service. By the same token, transparency around these cost components and their relationship to rates would enhance understanding of any rate design changes the Company may wish to pursue in future rate cases. Here, for example, instead of calculating the FCRC as explained above, we could derive it directly from CGS-NM customers' unbundled rates by only crediting the customer's energy charge for self-generated energy and not crediting the delivery portion of their bill.

Q. How would the proposed $3.53/kW/month FCRC compare to a delivery charge that would result from unbundling the energy rate?

A. For the average customer, the two charges would be almost identical, assuming the delivery charge were limited to the same unbundled distribution cost components. As I described previously, the distribution-related costs recovered in the energy charge for 2021 is $0.03316/kWh. For the 440 CGS-NM customers for whom we have complete 2018 data, the average solar output being netted is 454 kWh per month.

Multiplying these two figures yields a monthly charge of $15.05, which is very close to applying the $3.53/kW/month FCRC to the average peak output of 4.25 kW ($15.00).

Q. Why does WEPCO prefer the FCRC to the unbundling alternative?

A. Implementing an unbundled approach for all of WEPCO's rates, as other Wisconsin utilities have done, would require it to change how it bills more than 1 million accounts, as opposed to adding a single additional charge for those relatively few customers (currently well under 1,000) who have opted to add self-generation and take service on a net metering rate. Rather than requiring all of its customers to learn a new rate design in order to understand their bills, WEPCO prefers the FCRC for its CGS-NM customers, but is open to the unbundling alternative for the reasons I just discussed. If the Commission prefers to pilot unbundling, it would be reasonable to start with net metering customers.

<u>Residential Electric Vehicle Pilot</u>

Q. What is Wisconsin Electric's proposal for an electric vehicle ("EV") pilot program?

A. Wisconsin Electric proposes a new pilot tariff, the Residential Electric Vehicle Pilot ("REV Pilot"). The tariff will provide two principal benefits to customers.

First, it will allow residential customers to take advantage of time of use rates for charging an electric vehicle at their home while having the remainder of their electric usage billed according to their existing, underlying tariff.

Second, the proposed pilot will provide rebates of up to $1,000 to residential customers who install EV chargers at their homes. This rebate will offset the cost of installing EV chargers and accelerate the pace of their adoption, allowing Wisconsin Electric to study how EV charging will complement other grid-tied technologies, as well as where it may cause challenges.

Q. Which customers will be eligible for the REV Pilot?

A. The pilot will be available to residential customers on the Rg1, Rg2, and Fg1 tariffs.

Customers must install a qualifying system to be eligible for the REV Pilot. Qualifying systems are Level 2 systems operating at 240 volts that offer fast charging capability and are Underwriters Laboratories or Electrical Testing Laboratories certified. Customers must be in good standing (*i.e.*, they must have had no delinquent bills or disconnections in the past twelve months). As explained in Mr. Stasik's testimony, the rebates available under the REV Pilot will be capped at $7.5 million annually.

Q. How will customers take advantage of REV Pilot's rebate for EV chargers?

A. Customers must sign up for the REV Pilot to be eligible for a rebate and provide written evidence of EV ownership and installation of a qualifying system. Before they undertake the expense of installing EV charging, customers will be able to confirm with Wisconsin Electric's customer service department that rebates remain available for the year. Rebate checks will be sent to customers after they provide the required documentation and the Company has verified their eligibility for the tariff.

Q. How will Wisconsin Electric bill customers on the REV Pilot?

A. Customers will continue to take residential service on their underlying tariffs. The REV Pilot will require participating customers to have Wisconsin Electric install a second meter that will measure consumption for the EV charger only. The REV Pilot will incorporate time-of-use ("TOU") billing for this second meter, which will encourage customers to charge their vehicles overnight when system demand is lower. The TOU rates incorporated in the REV Pilot will be the same as the rates under Wisconsin Electric's existing Rg2 tariff. Customers may select as their On-Peak period the 12-hour window beginning at 7:00 A.M., 8:00 A.M., 9:00 A.M., or 10:00 A.M. Customers will pay an extra meter charge of $0.05951 per day to cover the cost of the second meter. Customers will receive bills that reflect the electric consumption at TOU rates for the EV charger, the balance of their electricity charges at underlying rates, the facilities charges and the extra meter charge.

Q. What does Wisconsin Electric expect to learn from offering the REV Pilot?

A. As EVs become more common, Wisconsin Electric needs to understand at least three potential effects their proliferation could have on generation and distribution resources.

First, Wisconsin Electric anticipates that charging EVs during off-peak hours will allow the utility to leverage generating and distribution capacity during periods when they are not fully utilized. EV charging also has the potential to increase overall electric consumption and to partially offset reductions in demand due to increasingly energy efficient households. This will allow fixed generation and distribution costs to be spread over more sales, thereby driving down rates for all customers, including those who do not have EVs.

Second, increased EV charging should complement wind generation, which tends to be greater at night. Thus, in the long run, increasing EV charging may improve the economics of wind generation relative to other sources of energy.

Third, it will be important to understand how increased EV charging will affect load on the distribution system, because a single EV can account for significant increased electric consumption at a residence. While Wisconsin Electric anticipates that it will be able to avoid material upgrades to the distribution system by implementing TOU rates, it will be important to understand customer behavior so that future, larger-scale deployments of EV charging technology maximize system savings without requiring costly distribution upgrades.

Wisconsin Electric believes that the REV Pilot's rebate will help to accelerate installation of at-home Level 2 chargers, thereby allowing the utility to understand the full effect of EVs on the distribution system and resulting impacts on costs for all customers.

Q. What is the timing for REV Pilot's implementation?

A. Wisconsin Electric proposes to make the REV Pilot available to customers January 1, 2021, and to enroll customers on a first-come, first-served basis.

Q. Is there precedent for this type of EV charging tariff?

A. Yes. Other state commissions have authorized similar programs, including the Michigan Public Service Commission, which recently approved tariffs for Consumers' Energy and Detroit Edison. This Commission has also approved a similar tariff for Madison Gas & Electric.

<u>Lighting</u>

Q. Is WEPCO proposing any changes to its Lighting rate schedules?

A. WEPCO is proposing to decrease lighting rates by 3.10% in TY 2020 and 1.31% in 2021 as shown on Ex.-WEPCO WG-Ferguson-1, Schedule 2, page 1 of 1, compared to the COSS recommendation of a 14.53% decrease in TY 2020 and a 3.32% increase in 2021.

Q. Are you proposing any other lighting changes?

A. Yes. Due to decreasing customer interest and the decreasing availability of higher pressure sodium ("HPS") and metal halide ("MH") fixtures, WEPCO is proposing to close the MS-3, MS-4, and GL-1 lighting schedules. In the last six months, roughly 2% of the roughly 1,100 light fixtures that the Company converted or installed were HPS, and no MH fixtures were installed.

The Company is also proposing minor changes to the lighting conditions of delivery as outlined in Schedule 11 of Ex.-WEPCO WG-Ferguson-1.

<u>Energy for Tomorrow</u>

Q. Is WEPCO proposing any changes to the Energy for Tomorrow program?

A. No. The Company has not made material additions to Renewable Energy Purchases or Company-owned renewable energy facilities since the EFT rates were set in the last rate case. Thus, the Company is not proposing any change to the EFT rates.

Rules and Regulations

Q. Please describe WEPCO's proposed changes to the Minimum Payment Options in Rule 406.2 of the Electric Rules and Regulations.

A. WEPCO proposes to modify the Minimum Payment Option language to allow increased flexibility in determining subsequent minimum payment amounts during the collection season beyond April to September. Schedule 11 of Ex.-WEPCO WG-Ferguson-1 displays WEPCO's proposed changes.

Q. Are you proposing any changes to the Company's Budget Billing program?

A. Yes. To simplify the Budget Billing program per preferences we have heard from our customers, we are proposing changes to Electric Rules and Regulations 407.4(c), which describes the periodic and continuous plans for Budget Billing.

Q. What is the Company's current Budget Billing structure for under-billed and over-billed amounts?

A. The Company currently offers Periodic and Continuous Budget Billing plans. Under the Periodic plan, in month 12 the customer is billed the difference between their actual costs during the budget billing service year and their budget billing installments. Under the Continuous plan, in month 12 this difference is rolled into and made part of the next year's monthly installment amount.

Q. What changes is the Company proposing and why?

A. Our experience shows that our current method of handling settlement balances in month 12 causes customer confusion. To reduce this confusion, we propose moving to a structure that incorporates elements from both plans. Customers have expressed that if they end up paying too much over a twelve-month period, they would like their balance credited to them as soon as possible. However, if they did not pay enough, they would prefer that debit balance to be spread over their payments for the following Budget Billing year.

Accordingly, we propose to modify our Budget Billing structure so that an under-billed (debit) balance is rolled into the next Budget Billing year's monthly installment amount, whereas an over-billed (credit) balance will be applied against the customer's account. Customers will remain able to contact us and opt to pay a debit balance in full, and to receive a credit balance as a refund or roll it into the next Budget Billing year's monthly installment amount if preferred.

Q. How will the Company communicate this change to its customers?

A. The annual service guide will explain the changes, and the Company's web page for Budget Billing will be updated to reflect the change. Additionally, as current Budget Billing customers reach the settlement month, a special message will be printed on their bill explaining the new options.

Q. When would the budget billing change take effect?

A. We propose making the changes effective on a rolling basis as Budget Billing customers settle their accounts after we implement our new billing system. Over the course of the year following implementation, all Budget Billing customers will reach month 12 and have their account settled per the new methodology.

Q. Is the Company proposing changes to its Energy Information Option?

A. Yes, we are proposing to close this offering to new accounts and new installations. Additionally, we are requesting to terminate this offering at a future date, without further Commission approval, when the Company is no longer able to deliver the option as offered due to hardware and/or software incompatibilities and limitations.

Q. Please describe the hardware and software issues you referenced.

A. In 2016, meter manufacturers stopped producing the communication technology utilized with this offering. Our existing meter supply is depleted to the point where the Company can only support and maintain existing customer installations. As to software, Meterlink software provides customers with dial-in access to their available 15-minute interval data from the billing meters. This software has limited remaining

vendor support due to compatibility issues with Oracle and Microsoft. When Meterlink is no longer functional, participating customers will not have dial-in access to their interval data. At this time, the end date for the Meterlink software is unknown. Additionally, the Company's customer presentment platform, known as Energy Analysis, is near its end of life. Altogether, these developments mean WEPCO will soon be unable to support the Energy Information Option.

<u>Miscellaneous Electric Rate Design Changes</u>

Q. Is WEPCO proposing to cancel any tariffs?

A. Yes. WEPCO is proposing to cancel CGS-7. As approved in Docket 05-UR-107, all customers were transferred from this rate schedule to CGS-NM in January of 2016.

Q. Are you proposing any other changes to the rules, regulations, and rate sheets?

A. Yes. We are proposing numerous minor changes as reflected in Schedule 11 of Ex.-WEPCO WG-Ferguson-1.

<u>Steam Utility</u>

<u>Description of Schedules</u>

Q. Please describe the contents of Schedule 12 of Ex.-WEPCO WG-Ferguson-1.

A. Schedule 12 shows a summary of current and proposed revenue for Wisconsin Electric's steam utility by rate schedule, including the proposed dollar and percent change for 2020.

Q. Please describe the contents of Schedule 13 of Ex.-WEPCO WG-Ferguson-1.

A. Schedule 13 shows the steam utility's test year billing data by rate schedule, current and proposed revenue, and dollar and percentage rate changes for 2020. The percentage rate change for each rate schedule is the percentage change for that billing unit. The proposed rates in this schedule reflect a fair and equitable distribution of WEPCO's jurisdictional revenue requirement, accounting for all pertinent factors.

Q. Please describe Schedule 14 of Ex.-WEPCO WG-Ferguson-1.

A. Schedule 14 shows the percentage increases applicable to the steam customers by frequency with the proposed rate increases.

<u>Steam Rate Schedules</u>

Q. Please describe the steam rate schedules.

A. We offer four rate schedules for our steam customers:

Ag1: Downtown Milwaukee Steam Firm Service. The majority of steam customers take service under this rate schedule. The rate structure includes a facilities charge, customer demand charge and energy charge.

Ag2: Downtown Milwaukee Steam with a Condensate Return Water Credit. There are currently no customers taking service under this rate schedule. The rate structure includes a facilities charge, customer demand charge, energy charge and a condensate water return credit.

Ag3: Economic Development Rate. There are currently two customers forecasted to take service under this rate in 2020. The rate structure includes a facilities charge, customer demand charge and energy charge. The energy charge varies by the number of months the customer has taken service under this tariff. Customers are subject to three timeframes: Months 1 to 60, Months 61 to 120, and Months 121 to 180. The energy rates increase the longer the customer stays on the rate.

Ag4: Downtown Milwaukee Steam Non-Firm Service. There are currently four customers forecasted to take service under this rate in 2020. The rate structure includes a facilities charge, customer demand charge and energy charge.

Q. Please describe the overall increase and rate design for these rate schedules and how they relate to the revenue requirement shown in Ex.-WEPCO WG-Nelson-12.

A. The 2020 revenue requirement shown in Ex.-WEPCO WG-Nelson-12 is $22,266,641. The present revenues are $21,308,619. The 2020 revenue requirement results in a 4.50% increase.

WEPCO is proposing an increase of 25% to all distribution charges (facilities and customer demand) for all four rate schedules. The current fuel credit is shown in present rates and is assumed to go to zero in the proposed rates.

Energy charges were decreased for each rate schedule to arrive at the $22,266,641 revenue requirement. All rate schedules were held at a 4.50% increase. To achieve these results, energy charges were decreased from 11% to 24% depending on the rate schedule.

Q. How does this proposed increase in the facilities charge and the customer demand charge affect the split in cost recovery between the facilities charge, customer demand charge and the energy charge?

A. WEPCO intends to move towards recovering costs based on the results of the cost classification analysis presented in Ex.-WEPCO WG-Nelson-12. About 72% of the costs to serve the steam utility are fixed and 28% are variable according to the analysis. Under the current rate design, about 86% of the costs are recovered with the variable energy charge and 14% are recovered with the facilities and customer demand charge. The proposed rate design would increase the cost recovery to about 17% through the facilities and customer demand charge.

Q. If the revenue requirement changes significantly due to the Staff audit, would your proposed revenue allocation change?

A. Yes. If that occurs, WEPCO will likely submit a revised rate design proposal based on the Staff audit.

<u>Other Steam Rate Changes</u>

Q. Have you calculated new values for embedded credits for expansion of the steam distribution systems?

A. Yes. The calculated values of embedded credits for expansion of the steam distribution systems are presented in Ex.-WEPCO WG-Ferguson-1, Schedule 15.

Q. How were the embedded credits calculated?

A. The embedded credits for the steam distribution system were derived in a manner similar to that prescribed for electric embedded credits in PSC 113.1006. The Commission's rules for steam in PSC 140 do not address embedded credits. The depreciated costs of the steam distribution systems are divided by the total steam sales using the distribution system.

Q. Is WEPCO proposing any other modifications related to its steam rates?

A. Yes. WEPCO is proposing to modify "Section 200 Extension of Steam Service" of its Rules and Regulations. These proposed revisions are included in redline formats at Schedule 11 of Ex.-WEPCO WG-Ferguson-1.

Q. Why is WEPCO proposing these modifications?

A. These modifications clarify that any steam distribution infrastructure installed to a serve a new development and reasonably expected to serve additional future customers would be subject to the Company's steam extension rules.

Q. Does this conclude your pre-filed direct testimony?

A. Yes, it does, but I may submit supplemental direct testimony addressing the standby rate and other, minor rate modifications that are still under development as of this filing, including modifications to non-firm rate schedules.